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Smith

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(54) **METHOD AND APPARATUS FOR TESTING AND TREATMENT OF A COMPLETED WELL WITH PRODUCTION TUBING IN PLACE**

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(51) **Int. Cl.**
E21B 47/00 (2006.01)

(52) **U.S. Cl.** **166/250.17**; 166/305.1; 166/113; 166/66

(58) **Field of Classification Search** 166/250.17, 166/305.1, 113, 66, 77.2, 50, 152
See application file for complete search history.

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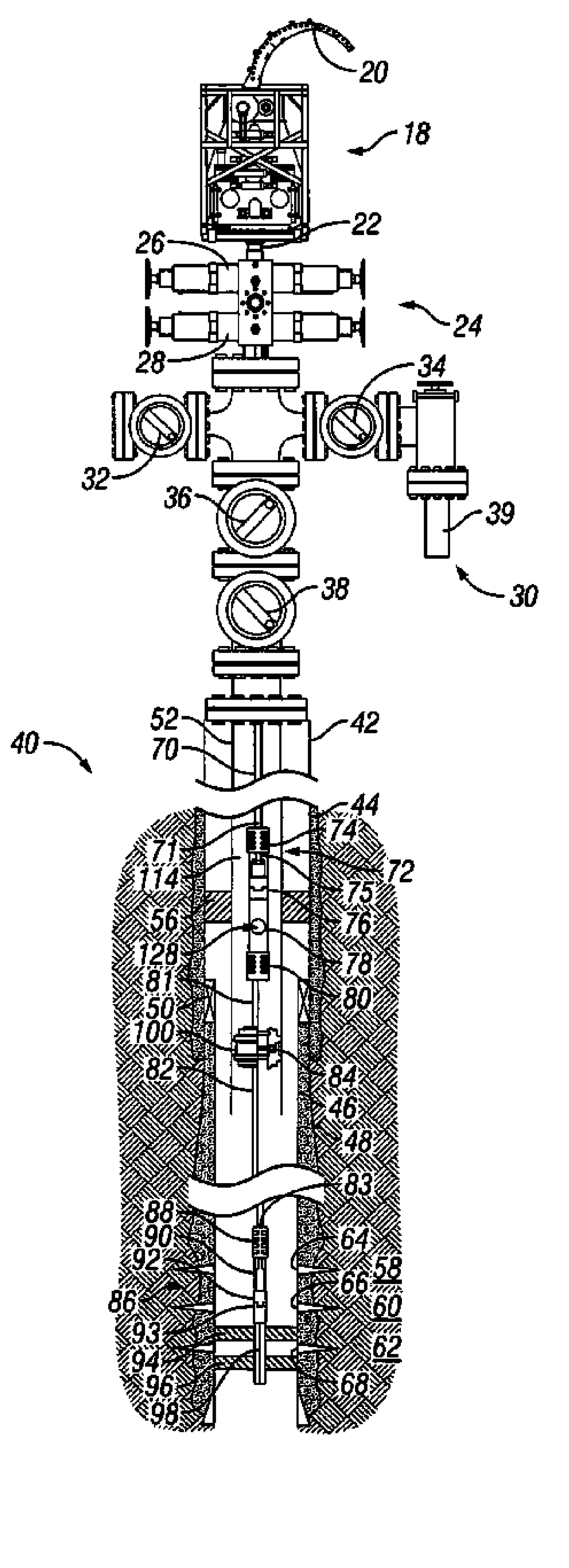
(57) **ABSTRACT**

A method and apparatus is used to test and/or treat individual production zones of a well in conjunction with a conventional coiled tubing unit. This method and apparatus allows testing and treatment of a well with production tubing in place. The return flowpath for formation fluids and/or treatment fluids is through the annulus between the coiled tubing and the production tubing. The preferred embodiment uses straddle packers, but alternative embodiments may use only a single inflatable packer.

6 Claims, 12 Drawing Sheets



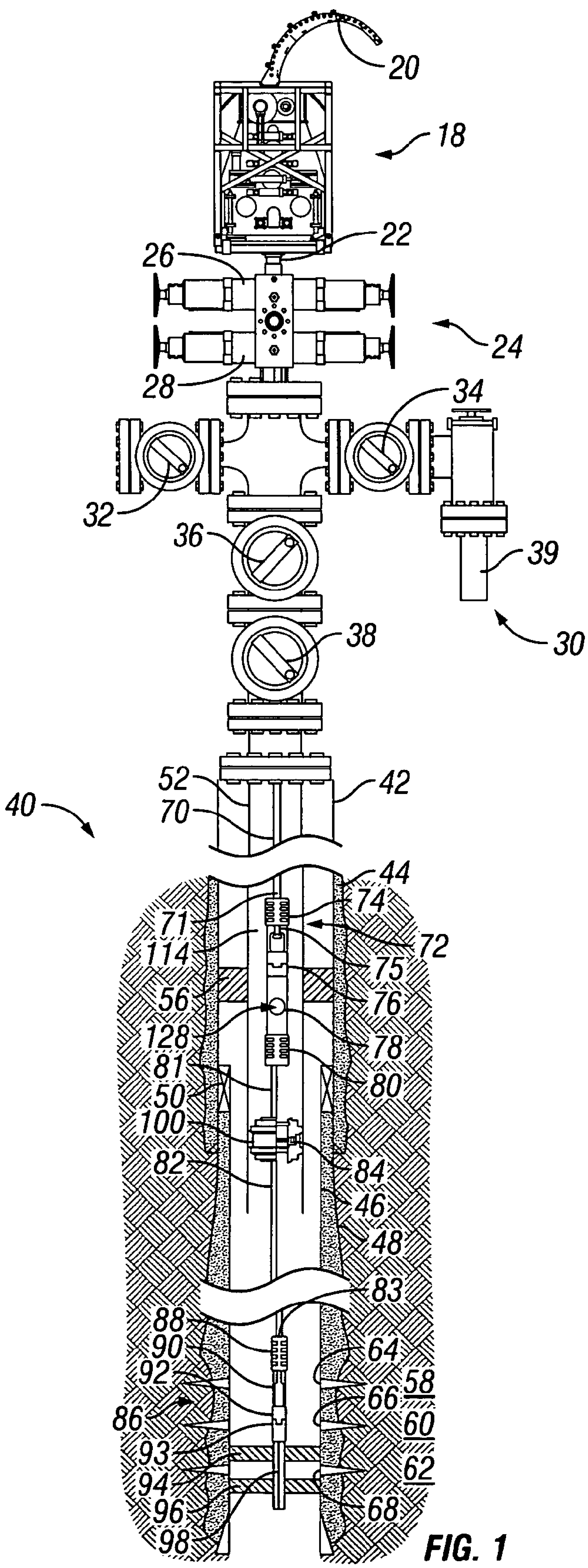

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FIG. 1

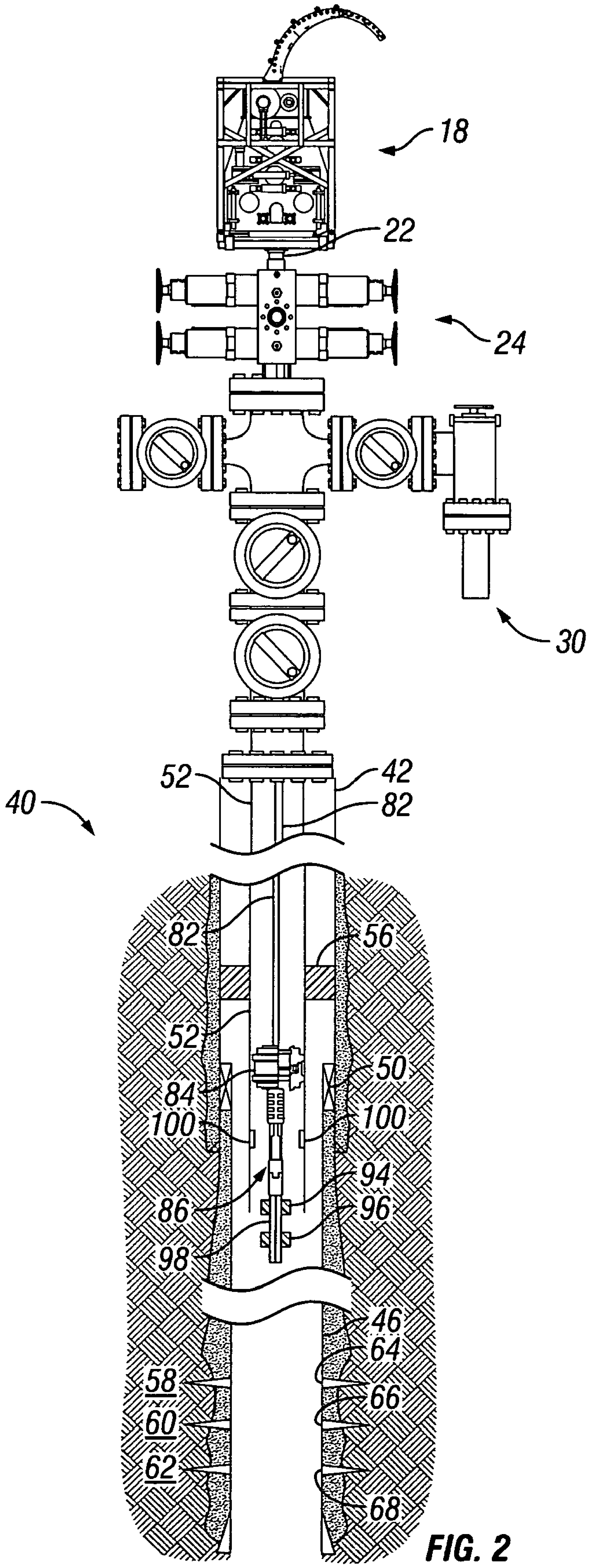
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FIG. 2

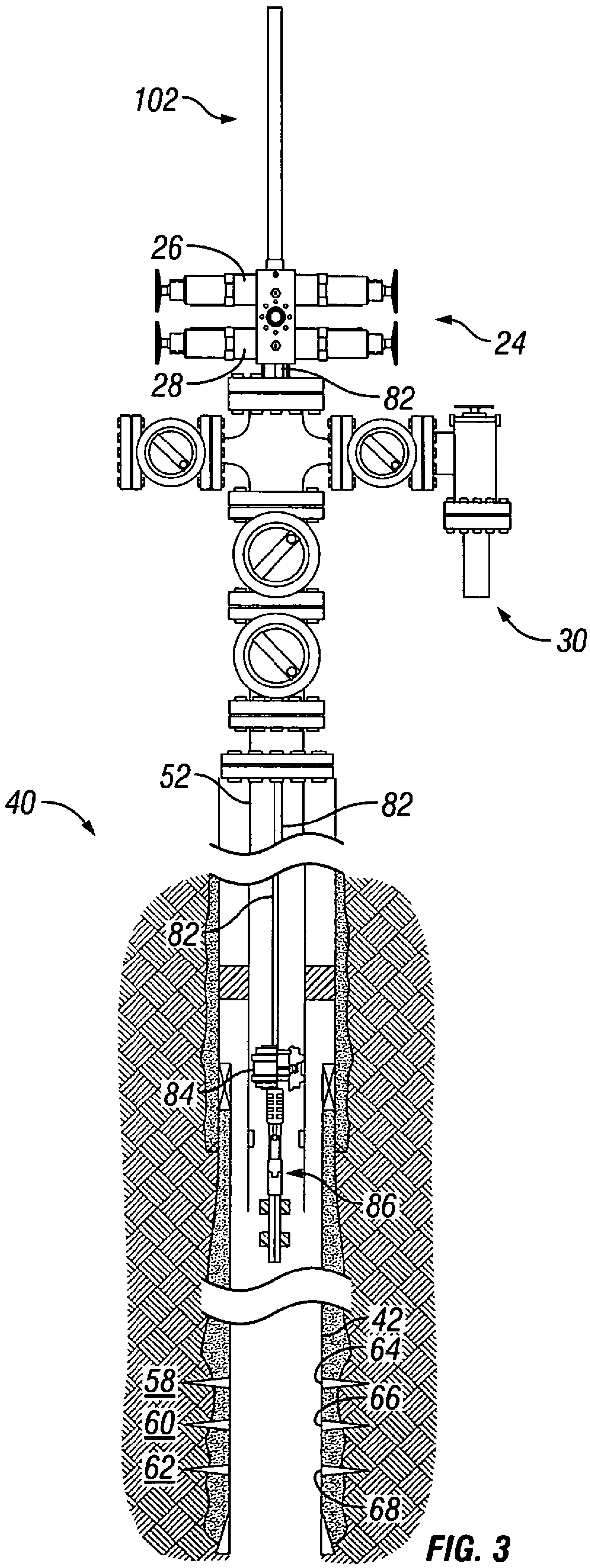

FIG. 3

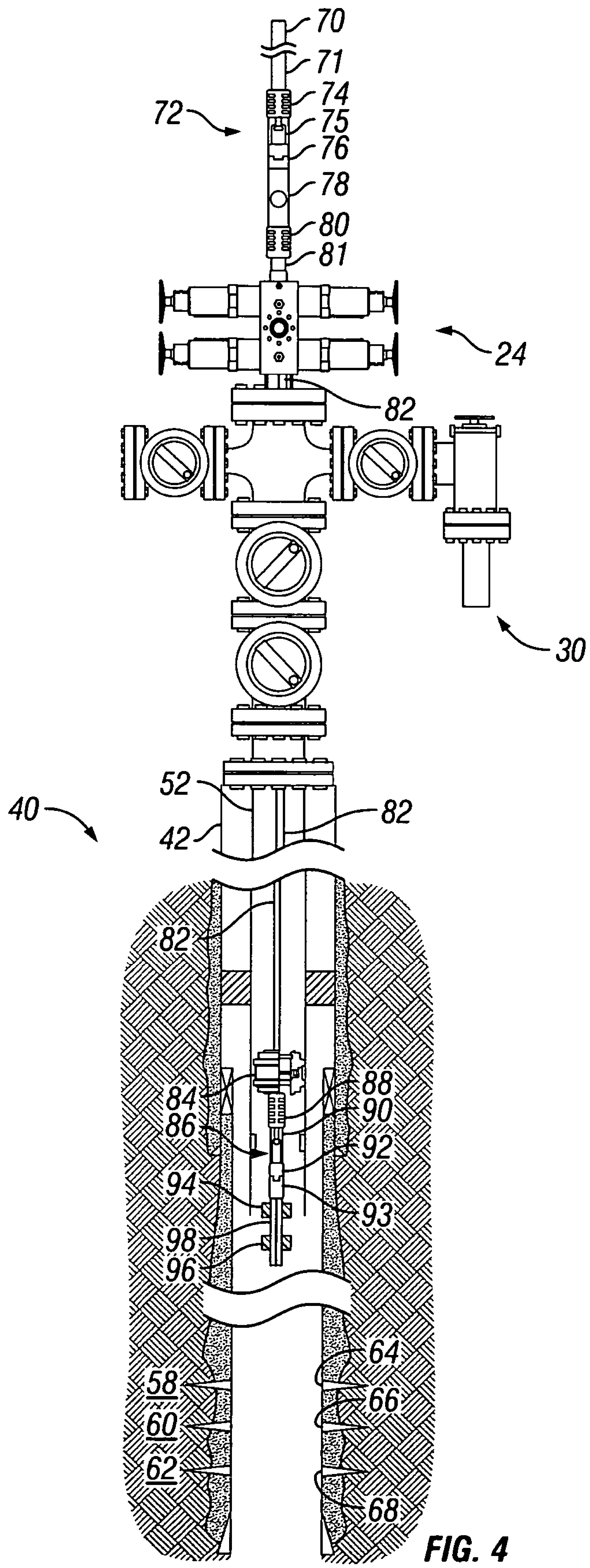
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FIG. 4

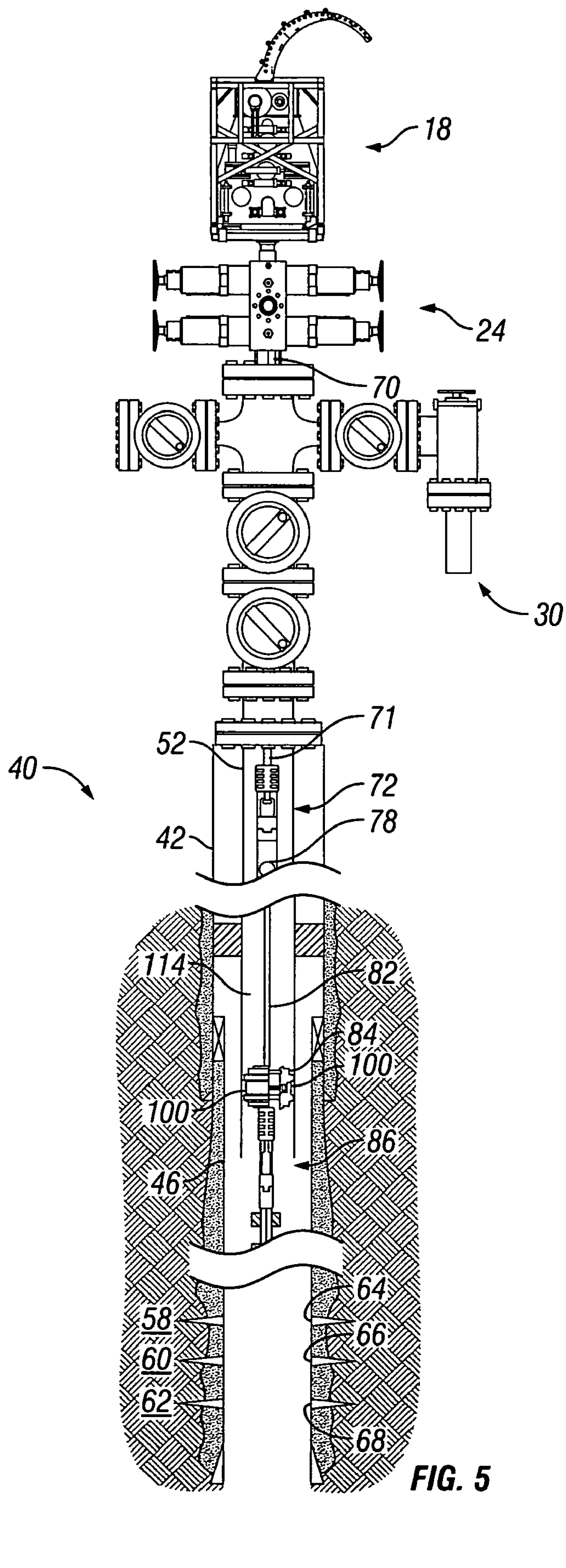


FIG. 5

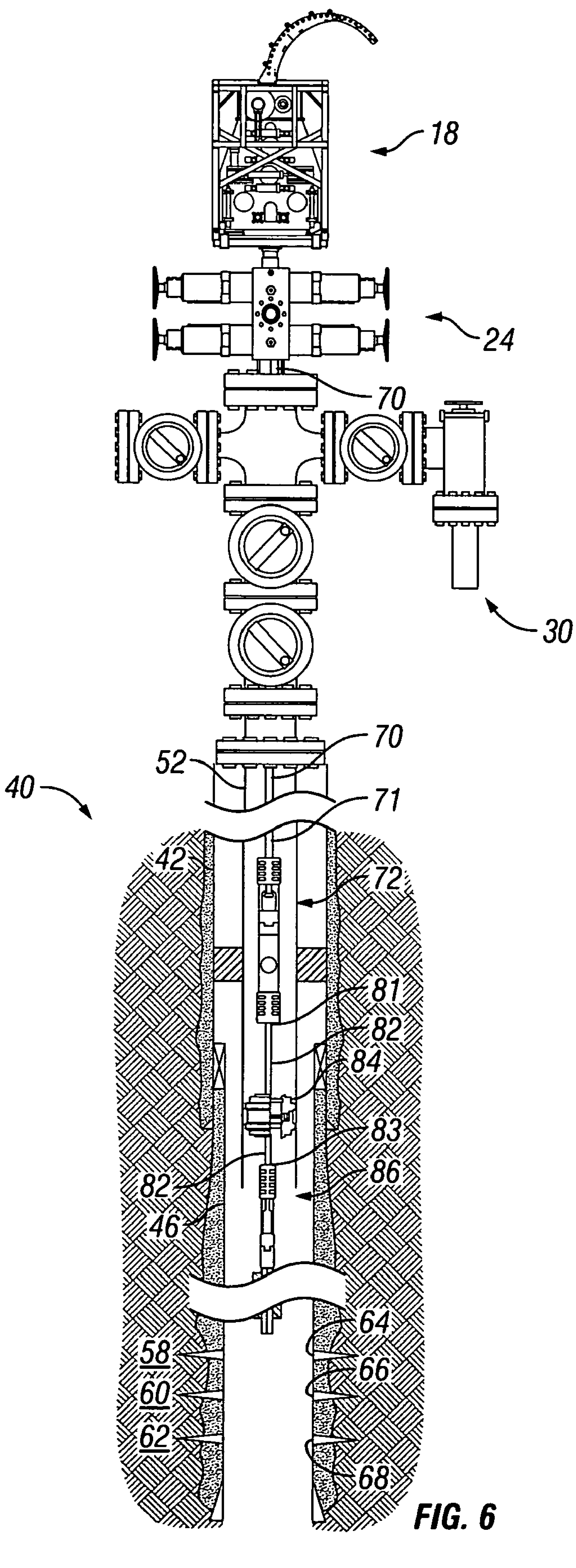
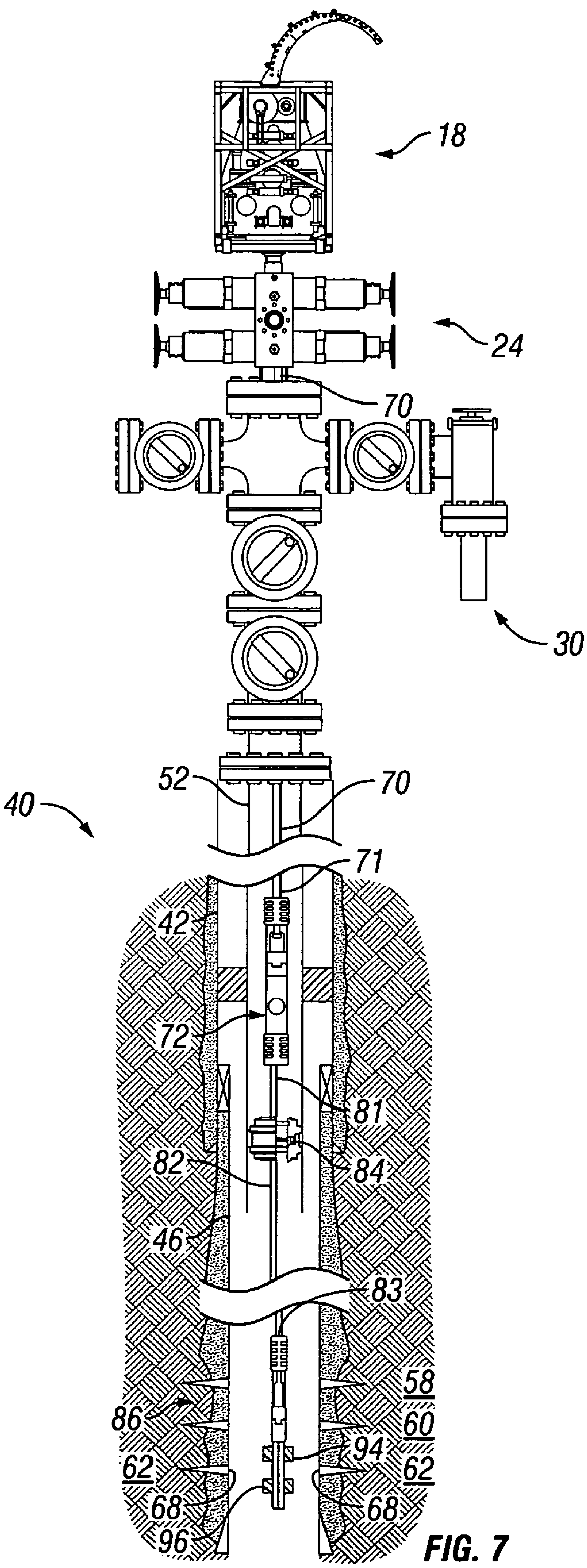


FIG. 6



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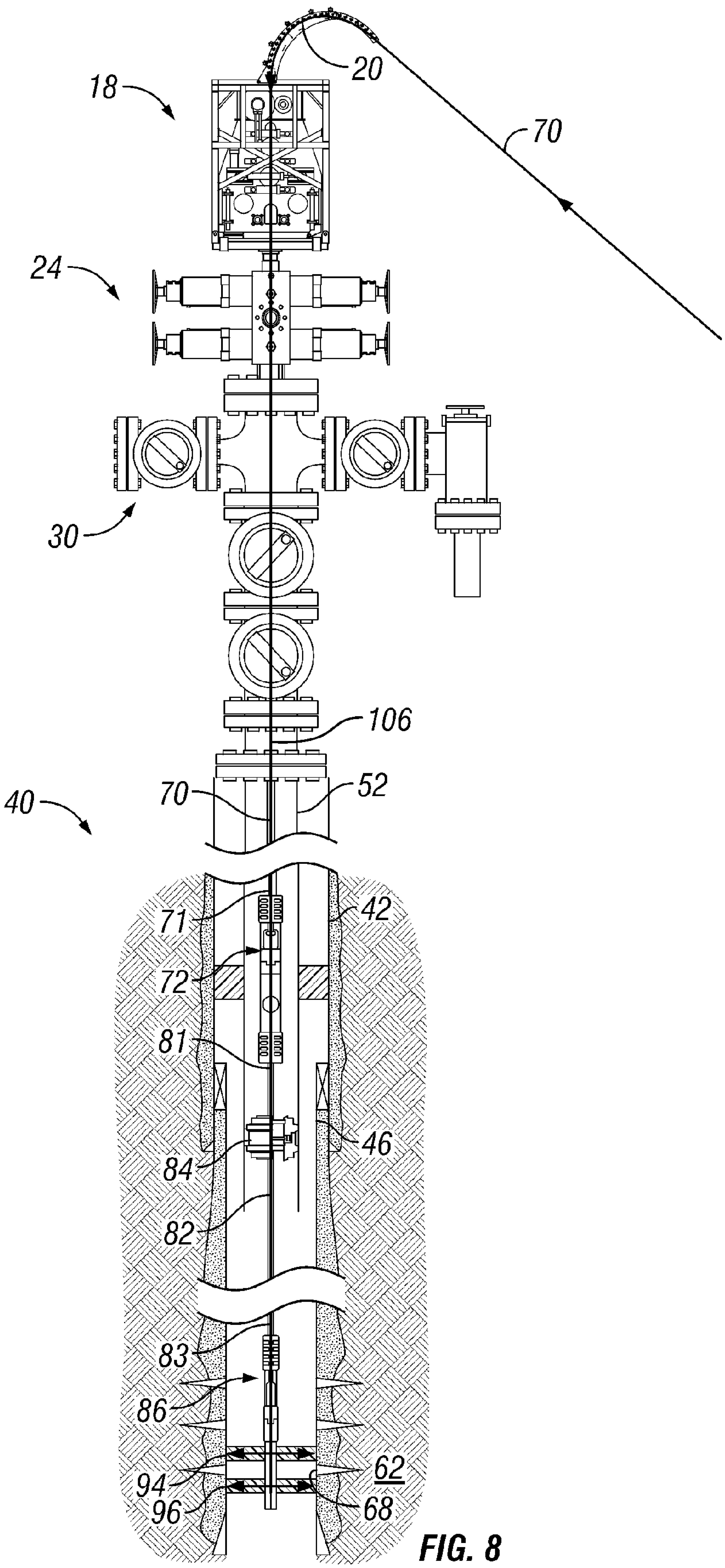

FIG. 8

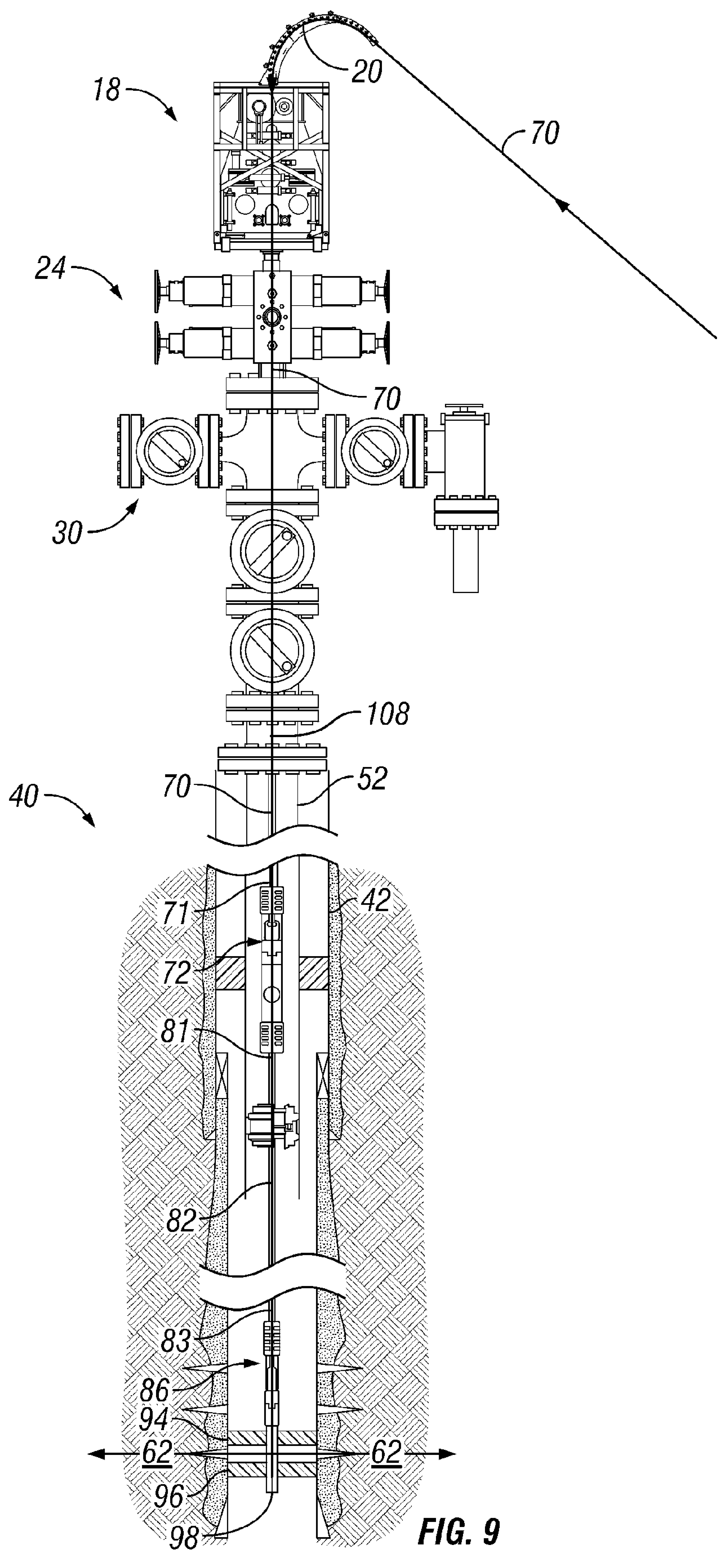

FIG. 9

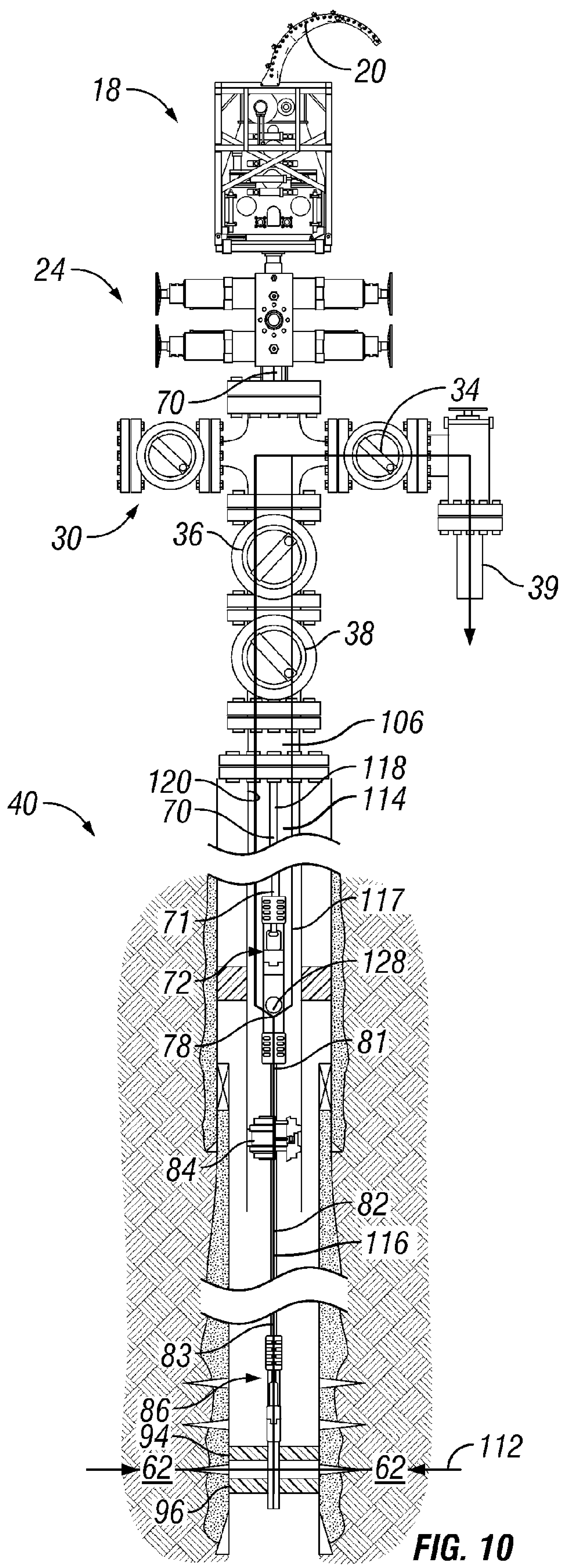
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FIG. 10

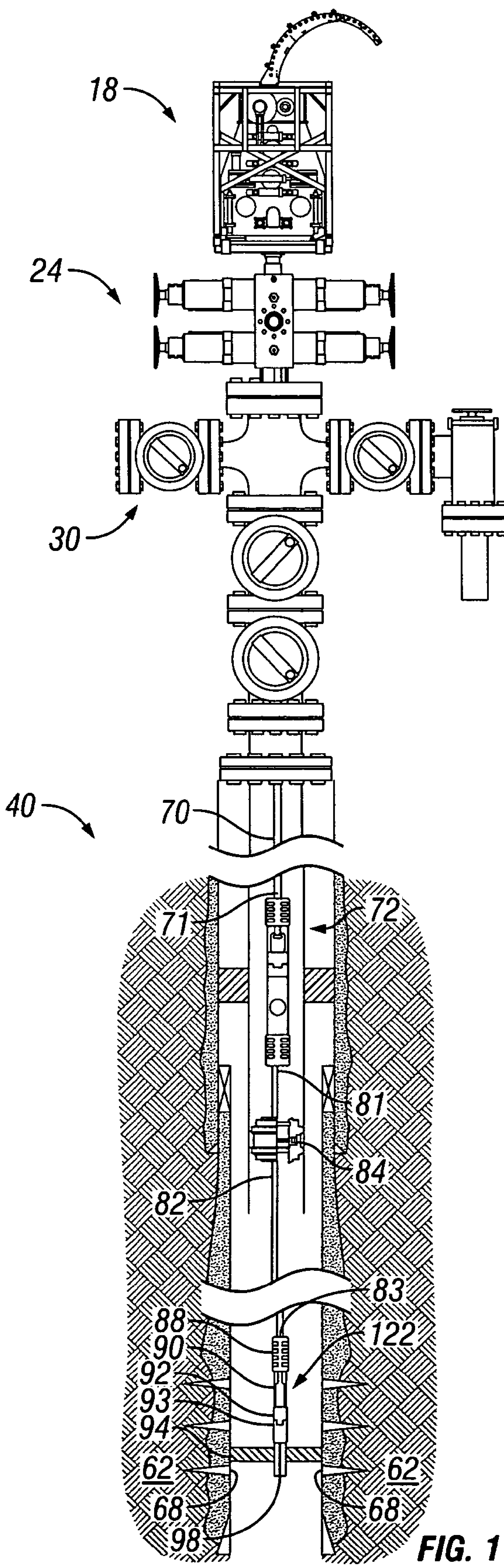

FIG. 11

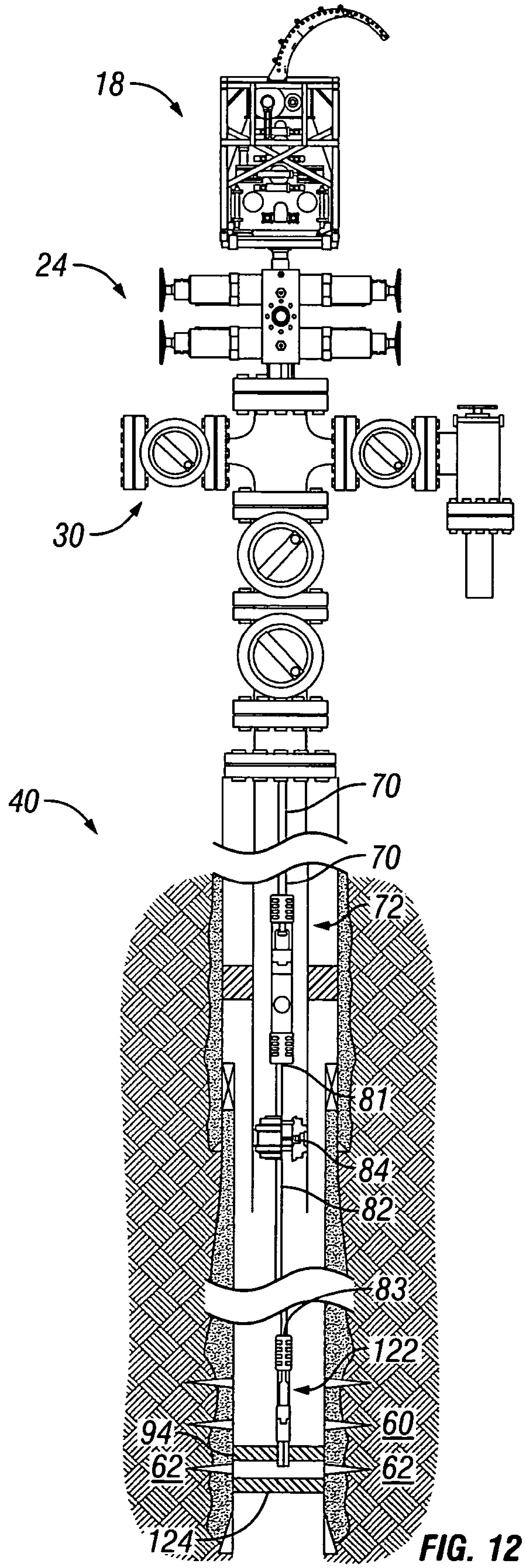

FIG. 12

METHOD AND APPARATUS FOR TESTING AND TREATMENT OF A COMPLETED WELL WITH PRODUCTION TUBING IN PLACE

CROSS REFERENCE TO RELATED APPLICATION

This application claims priority from U.S. Provisional Application entitled "Method for Coiled Tubing Treat and Cleanup/Test," Ser. No. 60/469,537, filed May 9, 2003, which is incorporated herein by reference.

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention relates to the testing and treatment of oil and gas wells, and in particular, to the testing and treatment of such wells with production tubing in place

2. Description of Related Art

Testing is necessary to evaluate a well. Production testing occurs at various stages in the life of a well. For example, drill stem testing can be performed in an open hole before casing is set to establish the contribution from each identified potential producing zone.

A single subsurface formation can be tested in an open hole for production potential before casing has been set or the well has been completed. In some wells, multiple subsurface formations will be tested for production potential. If the well is deemed to have production potential, the open hole will be cased and the casing will be perforated at the subsurface formations that have tested favorably for hydrocarbon production.

One approach to production testing is disclosed in U.S. Pat. No. 6,543,540. The '540 patent discloses a method for performing production testing in open holes and in cased holes that avoids transporting formation fluid to the surface. Formation fluid is conducted from a first, expected permeable formation to a second permeable formation, as opposed to prior art techniques where fluid is conducted between a formation and the surface.

After a well has been cased, it must be perforated. Wells are often tested again after perforation, but before production tubing has been set. U.S. Pat. No. 6,543,538 discloses a method for perforating and treating multiple wellbore intervals before production tubing has been installed. One embodiment involves perforating at least one interval of the one or more subterranean formations penetrated by a given wellbore, pumping the desired treatment fluid without removing the perforating device from the wellbore, deploying some item or substance in the wellbore to removably block further fluid flow into the treated perforations, and then repeating the process for at least one more interval of subterranean formation. Another embodiment involves perforating at least one interval of the one or more subterranean formations penetrated by a given wellbore, pumping the desired treatment fluid without removing the perforating device from the wellbore, actuating a mechanical diversion device in the wellbore to removably block further fluid flow into the treated perforations, and repeating the process for at least one more interval of subterranean formation.

Another method for testing a cased well without production tubing is disclosed in U.S. Pat. No. 6,527,052. In this disclosure, drill pipe or coiled tubing is connected to a formation test assembly for testing a cased well. In one embodiment, the test is performed downhole without flowing fluids to the earth's surface. In another embodiment, a formation is perforated and fluids from the formation are flowed into a large surge chamber associated with a tubular string installed in the well. In another embodiment, fluids from a first formation are flowed into a tubular string installed in the well, and the fluids are then disposed of by injecting the fluids into a second formation. In yet another embodiment, fluids are flowed from a first formation and into a second formation utilizing an apparatus which may be conveyed into a tubular string positioned in the well.

If the well still appears viable after casing and perforation, production tubing will be set to complete the well, or additional perforating may occur. Drill stem testing procedures are not suitable on a completed well with production tubing in place because the drill pipe and equipment often used in drill stem testing will not fit in the production tubing. Further, conventional flow testing equipment cannot be run in production tubing even if the equipment is run on a wire line or a slick line.

After a well has been in production, the production rate may decline over time for a number of different reasons. It may therefore be necessary and desirable to test one or more subsurface production zones to better evaluate the reasons for the decline in production. Conventional tests on completed wells with production tubing in place are typically less comprehensive than drill stem tests in the open hole or a cased hole. The other option is to remove the production tubing for a conventional drill stem test. This latter approach is expensive. There is therefore a need to be able to run separate tests of each production zone in a completed well with production tubing in place.

One solution is disclosed in U.S. Pat. No. 5,353,875. In the '875 Patent, testing may be accomplished without removing the production tubing string from the well. The production of the well is shut down and then a coiled tubing test string is run down into the production tubing string. The coiled tubing test string includes a conveyance coiled tubing string, a tester valve carried by the conveyance coiled tubing string, and a test packer carried by the conveyance coiled tubing string. The test packer is set within one of the casing bore and the production tubing bore above perforations which communicate the casing bore with a subsurface formation. Drawdown and buildup testing of the subsurface formation can then be accomplished by opening and closing the tester valve to selectively flow well fluid up through the conveyance coiled tubing string or shut in the conveyance coiled tubing string. After the drawdown/buildup testing is completed, the coiled tubing test string is removed from the well and production of the well is resumed up through the production tubing bore. The problem with the method of the '875 patent is that hydrocarbons flow to the surface through the coiled tubing. Use of this flowpath is typically not a favored procedure in the field. Therefore, there is still a need for a method and apparatus that will facilitate testing of one production zone at a time in a completed well with production tubing in place.

If the testing procedures indicate that there is a problem, it is often preferable to stimulate or otherwise treat an existing well to improve production rates, rather than drill a new well. There are a number of ways to treat a completed well with multiple production zones, including matrix acidizing. In the past, it has been common to treat all production zones at one time. The problem with this prior art technique is that large amounts of acid are pumped into the well. After the acid is returned to the surface, it must be disposed. Further, treatment of all production zones may not have been necessary because only one production zone may have had a problem. Therefore, there is a need for a method and apparatus that will facilitate treatment of one production zone at a time in a completed well with production tubing in place.

One technique that has been suggested for treatment of one production zone at a time in a completed well with production tubing in place is described in U.S. Pat. No. 5,350,018. This technique uses inflatable packers to isolate a production zone. Treatment fluid is pumped down the coiled tubing to the zone and the treatment fluid and hydrocarbons flow back up the coiled tubing after the treatment. Again, it is desirable to avoid flowing hydrocarbons up the coiled tubing to the surface. There is still a need for a method and apparatus that avoids return flow through the coiled tubing. (See also U.S. Pat. No. 4,913,231).

A downhole stripper is used in the present invention. This downhole stripper is an existing electric submersible pump (ESP) bypass logging plug already available but not used in the same way as the present invention. Both PCE and Phoenix Petroleum Services market this logging plug.

An annular control tubing injection valve, sometimes referred to as an ACTIV, is also used in the present invention. Prior art exists on annular communication tools, such as a pick-up unloader used in packer operations marketed by Petro Tech Tools, a division of Schlumberger, as Product No. 3544. The pick-up unloader is tension and compression-activated. The pick-up unloader is a simple version of an ACTIV. Schlumberger pressure pulse technology (IRIS) may also be used to open and close the ACTIV.

BRIEF SUMMARY OF THE INVENTION

The present invention is a method and apparatus for testing and/or treatment of a single production zone and/or multiple production zones in a completed well with production tubing in place. A conventional coiled tubing unit is utilized to insert and retrieve unique downhole tool assemblies. The conventional coiled tubing unit includes the coiled tubing reel, a control cabin, power pack, injector head assembly, and blow-out preventer (BOP) stack. Various types of BOP's may be used but quad BOP's are often encountered. Quad BOP's frequently include blind rams, shear rams, slip rams, pipe rams, and equalizing valves.

The preferred embodiment of the present invention includes a conventional coiled tubing unit at the surface. The coiled tubing string from the reel connects to a downhole conveyance assembly, which connects to a conveyance coiled tubing string, which connects to a downhole test/treat assembly. The preferred embodiment also includes a downhole stripper removably set in the production tubing, through which the conveyance tubing string can move. The downhole conveyance assembly includes several components one of which is the annular control tubing injection valve (ACTIV), previously discussed. The downhole test/treat assembly includes several components, one of which is called a drag spring reversing check valve which will sometimes be referred to as a "DSRV". The drag spring reversing valve is disclosed in U.S. patent application Ser. No. 10/254,134, filed on Sep. 25, 2002, which application is incorporated herein by reference.

The present method utilizes a flow path for the well fluid and/or treatment fluid that differs from the prior art. An annulus is defined between the coiled tubing and the production tubing above the stripper. Well fluid and/or treatment fluid flows up through this annulus between the production tubing and the coiled tubing above the ACTIV. This unique annular flow path avoids hydrocarbons and treatment fluid passing up the coiled tubing string to the wellhead on the surface.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** is a partial sectional view of a well with production tubing in place and the apparatus of the present invention in the hole with inflatable packers inflated to isolate a single production zone for testing and/or treatment.

FIG. **2** is a partial sectional view of the well of FIG. **1** with production tubing in place and the downhole test/treat assembly run in the hole near the terminus of the production tubing.

FIG. **3** is a partial sectional view of the well of FIG. **1** with production tubing in place and the injector head assembly removed to expose a portion of the conveyance coiled tubing string.

FIG. **4** is a partial sectional view of the well of FIG. **1** with production tubing in place, with the downhole test/treat assembly run in the hole and connected to the conveyance coiled tubing string and the downhole conveyance assembly connected on one end to the conveyance coiled tubing and on the other end to the coiled tubing string.

FIG. **5** is a partial sectional view of the well of FIG. **1** with production tubing in place, with the injector head assembly in place and the downhole stripper proximate the landing nipples.

FIG. **6** is a partial sectional view of the well of FIG. **1** with production tubing in place, with the downhole test/treat assembly and the downhole conveyance assembly run in the hole.

FIG. **7** is a partial sectional view of the well of FIG. **1** with production tubing in place and the downhole test/treat assembly run into the hole to a depth proximate a production zone.

FIG. **8** is a partial sectional view of the well of FIG. **1** with production tubing in place and the inflatable packers inflated to isolate a single production zone for treatment and/or testing.

FIG. **9** is a partial sectional view of the well of FIG. **1** with production tubing in place and treatment fluid being injected into a single production zone that has been isolated by the inflatable packers.

FIG. **10** is a partial sectional view of the well of FIG. **1** with the production tubing in place and treatment fluid and formation fluid from the production zone flowing back to the wellhead. The same flowpath is utilized during a test of the production zone, except only formation fluid flows back to the wellhead.

FIG. **11** is a partial sectional view of the well of FIG. **1** with production tubing in place with an alternative embodiment of the present invention that utilizes a single packer.

FIG. **12** is a partial sectional view of a well with production tubing in place with another alternative embodiment of the present invention that utilizes a single packer and a mechanical or inflatable bridge plug previously run and set in the well.

DETAILED DESCRIPTION OF THE INVENTION

FIG. **1** is a partial sectional view of a well with production tubing in place and the apparatus of the present invention in the hole with inflatable packers inflated to isolate a single production zone for testing and/or treatment. A conventional coiled tubing unit is positioned on the wellhead.

The conventional coiled tubing unit includes a coiled tubing reel, not shown, a power plant, not shown, a control cabin, not shown, and an injector head assembly generally identified by the numeral **18**. The injector head assembly **18** includes a gooseneck **20** and a stripper **22**. A BOP assembly is generally identified by the numeral **24**, having at least slip rams **26** and pipe rams **28**. The configuration of a conventional coiled tubing unit is well known to one skilled in the art.

A wellhead **30**, sometimes know in the industry as a Christmas tree, includes a first valve **32**, a second valve **34**, a third valve **36**, a fourth valve **38** and a wellhead outlet **39**. Various valve configurations are possible at the wellhead **30** and this arrangement is merely illustrative of one such configuration.

A well is generally identified by the numeral **40**. Casing **42** is shown set in the hole with cement **44**. A production casing liner **46** is shown set in the hole with cement **48**. A hanger liner with packoff **50** seals the outer circumference of the production casing liner **46** to the inner circumference of the casing **42** as is generally known to one skilled in the art.

Production tubing **52** has been placed in the casing **42** and sealed with a completion packer **56**. The well **40** has a first subterranean production zone **58**, a second subterranean production zone **60** and a third subterranean production zone **62**. First perforations **64** extend through the production casing liner **46** into the first production zone **58**. Second perforations **66** extend through the production casing liner **46** into the second production zone **60**. Third perforations **68** extend through the production casing liner **46** into the third production zone **62**.

A coiled tubing string **70** connects to the downhole conveyance assembly, generally identified by the numeral **72**. The downhole conveyance assembly **72** includes a connector **74**, a standard check valve **75**, a release joint **76**, an annular control tubing injection valve **78** (ACTIV) and a connector **80**. The connector **74** connects to the terminus **71** of the coiled tubing string **70**. The connector **80** connects to the upper terminus **81** of conveyance coiled tubing string **82**.

The ACTIV has two positions. The first position is closed which allows fluid to pass through the coiled tubing string **70**, through the downhole conveyance assembly **72**, including the ACTIV to the conveyance coiled tubing string **82**, discussed below. While going into the well, the ACTIV can either be in the open or closed position. The second position of the ACTIV is open. The ACTIV is placed in the open position during testing and in the closed position during treatment of the well. In the open position, fluid from production zones in the well flows up to the ACTIV and out open ports **128** to an annulus **114**, as discussed in connection with FIG. **10** below.

A downhole stripper **84** surrounds the conveyance coiled tubing string **82**. The test/treat assembly generally identified by the numeral **86** includes a connector **88**, a drag spring reversing valve **90** (DSRV), a release joint **92**, a logging tool assembly **93**, a first inflatable packer **94** and a second inflatable packer **96** positioned on a spacer pipe **98**. The connector **88** connects to the lower terminus **83** of the conveyance coiled tubing string **82**. The structure and operation of the DSRV are fully described in the previously identified patent application.

Landing nipples **100** are positioned inside the production tubing **52**. The downhole stripper **84** has engaged the landing nipples **100** and the conveyance coiled tubing string **82** passes up and down through the downhole stripper **84**.

FIG. **2** is a partial sectional view of the well **40** of FIG. **1** with production tubing **52** in place. The downhole test/treat assembly **86** has been deployed in the well **40** inside the production tubing **52**. A sufficient length of the conveyance coiled tubing string **82** has been deployed in the well so the downhole stripper **84** is proximate the landing nipples **100**. In this view, the downhole stripper **82** has not yet engaged the landing nipples **100**. The inflatable packers **94** and **96** have not been inflated.

FIG. **3** is a partial sectional view of the well **40** of FIG. **1** with production tubing **52** in place and the injector head assembly **18** removed to expose a portion **102** of the conveyance coiled tubing string **82**. The conveyance coiled tubing string **82** is hung off the BOP **24** using the pipe slip rams **28**. The rams **26** are used for well control contingency purposes. The exposed portion **102** of the conveyance coiled tubing string **82** is cut off prior to connection of the downhole conveyance assembly **72** as shown in FIG. **4**.

FIG. **4** is a partial sectional view of the well **40** of FIG. **1** with the production tubing **52** in place, with the downhole test/treat assembly **86** run in the well and connected to the conveyance coiled tubing string **82**. While the injector head assembly, not shown, is suspended above the BOP assembly **24** the connector **80** of the downhole conveyance assembly **72** is connected is connected to the upper terminus of the conveyance coiled tubing string **82**. The connector **74** of the downhole conveyance assembly is connected to the terminus **71** of the coiled tubing string **70**.

FIG. **5** is a partial sectional view of the well **40** of FIG. **1** with the production tubing **52** in place. The injector head assembly **18** is repositioned on the BOP assembly. The coiled tubing **70** is run into the hole to a depth where the downhole stripper **84** is properly aligned with the landing nipples **100**. The downhole stripper **84** is engaged with the landing nipples **100** which seals the production tubing to fluid flow from the production zones **58**, **60** and **62**.

FIG. **6** is a partial sectional view of the well **40** of FIG. **1** with production tubing **52** in place. The coiled tubing string **70** has been run further into the well. This allows the conveyance coiled tubing string **82** to slide through the downhole stripper **84** with the downhole test/treat assembly **86** being lowered deeper into the well.

FIG. **7** is a partial sectional view of the well **40** of FIG. **1** with production tubing **52** in place. The coiled tubing **70** has been run further into the well. This allows the conveyance coiled tubing string **82** to slide through the downhole stripper **84** with the downhole test/treat assembly **86** being positioned proximate the third production zone **62** and the third perforations **68**. The packers **94** and **96** are positioned above and below the third perforations **68** prior to inflation, which is shown in the next figure.

FIG. **8** is a partial sectional view of the well **40** of FIG. **1** with the production tubing **52** in place. Fluid **106** is pumped through the coiled tubing string **70**, to inflate the first inflatable packer **94** and the second inflatable packer **96**. The fluid **106** passes through the coiled tubing string **70**, the downhole conveyance assembly **72**, the conveyance coiled tubing string **82**, and into the downhole test/treat assembly **86** to the inflatable packers **94** and **96**. The fluid **106** inflates the inflatable packers as shown in this figure to isolate a single production zone for testing and/or treatment. In this view, the third production zone **62** has been isolated for testing and/or treatment. By repositioning the inflatable packers in the well, the first production zone **58** or the second production zone **60** could also be selectively isolated for testing and/or treatment.

FIG. **9** is a partial sectional view of the well **40** of FIG. **1** with the production tubing **52** in place. Treatment fluid **108** is pumped from a tanker truck or other large container, not shown by a pump, not shown, into the third production zone **62** that has been isolated by the inflatable packers **94** and **96**. The treatment fluid **108** passes through the coiled tubing string **70**, the downhole conveyance assembly **72**, the conveyance coiled tubing string **82** and the downhole test/treat assembly **86** where it is isolated between the first inflatable packer **94**, the second inflatable packer **96** and the inside circumference **110** of the production casing liner **46**. Because the treatment fluid **108** is pumped under pressure, it then passes through the third perforations **68** into the third production zone **62**. If the treatment procedure is matrix acidizing, the treatment could consist of hydrochloric acid or any other suitable acid or treatment fluid. Other treatment procedures can be used with this invention including the pumping of solvents to remove waxes or asphaltenes, gels for water or gas shut off.

FIG. **10** is a partial section view of the well **40** of FIG. **1** with the production tubing **52** in place. Treatment fluid **108** and formation fluid **112** from the third production zone **62** become commingled fluids **116** and flow back to the wellhead **30**. The commingled fluids **116** exit the wellhead at the wellhead outlet **39**. The commingled fluids **116** thereafter enter a pipeline, not shown or a tanker truck, not shown for processing.

The annular flowpath **117** of the commingled fluids **116** is as follows: through the downhole test/treat assembly **86**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the annular control tubing injection valve (ACTIV) **78** into the annulus **114** up to and out the wellhead **30**. The annulus **114** is formed between the outside circumference **118** of the coiled tubing string **70** and the inside circumference **120** of the production tubing **52**. The annulus **114** is isolated from the well by the downhole stripper **84** and the BOP assembly **24**. The same annular flowpath **117** is utilized during a test of a production zone, except formation fluid flows **112** flow back to the wellhead **30** instead of the commingled fluids **116** that flow back after a treatment of the well **40**.

The annular flowpath **117** up the annulus **114** to the wellhead **30** is unique in the field of test and/or treatment of wells with production tubing in place. The annular flowpath **117** avoids flowing hydrocarbons to the surface through the coiled tubing **70**, which is advantageous, for the reasons discussed above.

FIG. **11** is a partial sectional view of the well **40** of FIG. **1** with production tubing **52** in place. An alternative embodiment of the present invention is shown. The alternative embodiment of a downhole test/treat assembly **122** only utilizes a single packer **94** instead of the inflatable packers **94** and **96** used in the downhole test/treat assembly **86**. Further, this alternative embodiment of the downhole test/treat assembly **122** is only able to test/treat a single production zone and it must be the deepest production zone in the well. In this figure, the deepest production zone is the third production zone **62**. Otherwise, the method of testing and treatment of the production zone **62** is the same as previously described for the primary embodiment in the preceding figures. The downhole test/treat assembly **122** includes a connector **88**, drag spring reversing valve (DSRV) **90**, a release joint **92**, a logging tool assembly **93**, a first straddle packer **94** and a spacer pipe **98**.

FIG. **12** is a partial sectional view of the well **40** of FIG. **1** with production tubing **52** in place. In this alternative embodiment of the present invention, a mechanical or inflatable bridge plug **124** has been previously run and set in the well below the production zone of interest. In this figure, the bridge plug **124** has been set below the second production zone **60**. The alternative embodiment of the downhole test/treat assembly **122** that utilizes a single packer **94** is positioned above the production zone of interest. In this figure, the first inflatable packer **94** is positioned above the second production zone **60**. Therefore, the second production zone **60** has been isolated for test and/or treatment. The second production zone **60** has been isolated by the first inflatable packer **94** on the downhole test/treat assembly and the bridge plug **124**. The method of testing and/or treatment of the production zone **60** is the same as previously described for the primary embodiment in the preceding figures.

Operational Example for Test/Treat

The following example is hypothetical. A well is approximately 10,000 feet deep with a first production zone at approximately 8750 feet, a second production zone at approximately 8850 feet deep and a third production zone at approximately 9000 feet deep. Casing has been set to approximately 8600 feet in the hole followed by a production casing liner for approximately from 8500 to 10000 feet. Production tubing has been installed to approximately 8700 feet. A hanger liner with packoff **50** has been set between the casing and the production casing liner at approximately 8550 feet. Landing nipples are positioned in the production tubing at approximately 8600 feet. The completion packer **56** is set at about 8450 feet between the casing and the production tubing.

A conventional coiled tubing unit is brought to the well and the well is shut in. The BOP assembly is connected to the wellhead and the injector head assembly is mounted on the BOP assembly. The downhole test/treat assembly **86** is connected to the lower terminus **83** of the conveyance coiled tubing string **82**. The downhole test/treat assembly and the conveyance coiled tubing string are deployed into the injector head assembly and the BOP assembly and run into the production tubing **52** to a depth of about 500 feet as shown in FIG. **2**. As shown in FIG. **3**, the injector head assembly **18** is removed, exposing a portion of the conveyance coiled tubing string which is cut off.

As shown in FIG. **4**, the downhole conveyance assembly **72** is connected to the upper terminus **81** of the conveyance coiled tubing string and to the terminus **71** of the coiled tubing string **70**.

As shown in FIG. **5**, the injector head assembly is, reconnected to the BOP stack and the downhole test/treat assembly **86**, the downhole stripper **84** and the downhole conveyance assembly **72** are run into the well to a depth of about 8600 feet. While running into the well, the ACTIV is closed to the annulus **114**. While running in the well the DSRV is closed to reverse flow, up towards the surface. At this depth the downhole stripper **84** is proximate the landing nipples **100**. Sufficient compressive force is then applied to the coiled tubing string **70**, which is transmitted through the conveyance coiled tubing string **82** to the downhole stripper **84** which locks it in place with the landing nipples **100**. When the downhole stripper is locked in place at about 8600 feet, it also seals the production tubing and isolates it from the rest of the well.

Additional compressive force on the coiled tubing string **70** releases the downhole stripper from the downhole test/treat assembly **86**. This allows the conveyance coiled tubing string **82** to slip through the downhole stripper **84** as more of the coiled tubing string **70** is run in the well as best seen in FIG. **6**.

The packers **94** and **96** are positioned so they straddle the third production zone **62** at about 9,000 feet. As shown in

FIG. 7. Once the straddle packers have reached the desired setting depth, the coiled tubing string **70** will be moved up hole to deactivate the check valves in the DSRV. This will then allow both direct flow down into the well and reverse flow up to the surface. Again, the structure and operation of the DSRV are more fully described in the prior patent application identified above and incorporated herein by reference.

A pump, not shown, pumps fluid down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **86** to inflate the straddle packers **94** and **95** as shown in FIG. **8**. When the packers have been set, the third production zone **62** is isolated from the rest of the well by the packers which seal against the inside circumference of the production casing liner **46**.

To test the third production zone, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**. The well is allowed to flow from the third production zone as shown in FIG. **10**, through the downhole test/treat assembly **86**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the ACTIV **78** into the annulus **114**. The formation fluid passes through the wellhead and out the wellhead outlet **39**. The logging tool assembly **93** measures flow, temperature and other variables to test the third production zone **62**. Data from the logging tool **93** can be sent in real time up to the surface by electric wireline logging cable, preinstalled in the coiled tubing. In the alternative, the data can be stored in memory and analyzed after the logging tool is removed from the well. In the preferred embodiment, the data is sent to the surface while the logging tool assembly is still in the well. Other production zones may be tested individually by deflating the straddle packers and repositioning the downhole test/treat assembly to the next zone. The packers are then reinflated and formation fluid is allowed to flow to the surface. After all zones of interest have been tested, it is time to treat one or more production zones. The present invention allows different zones to tested selectively. The test results may show that only one production zone needs treatment.

Assuming that only the third production zone **62** needs treatment, it is not necessary to reposition the packers from the location shown in FIG. **10**. In order to treat the third production zone **62**, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV to the closed to annulus position and, when weight is set back down, the ACTIV open ports **128** then prevent annular communication. The treatment fluid is pumped down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **86** as shown in FIG. **9** into the third production zone **62**. After a sufficient amount of treatment fluid has been pumped in the well, the pump is stopped.

The coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, and when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**.

The flowpath for the comingled fluid is the same as shown in FIG. **10**. The commingled fluid flows from the third production zone, through the downhole test/treat assembly **86**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the open ports **128** of the ACTIV **78** into the annulus **114**. The commingled fluid flows up the annulus **114** to the wellhead and out the wellhead outlet **39**. This flowpath up the annulus instead of the coiled tubing **70** differentiates the present method for the prior art for both testing and treatment of a well. After the formation has cleared itself of the treatment fluid, the production wing valves in the wellhead can be closed to stop the flow.

Once a treatment is completed, the straddle packers can be unset with tension applied and moved uphole to treat another production zone, if necessary. Once all production zones have been treated, the downhole test/treat assembly **86** is retrieved from the well. On the way out of the well, the downhole stripper **84** is disengaged and retrieved with the downhole test/treat assembly.

Operational Example for Treatment of a Well

The following example is hypothetical. A well is approximately 10,000 feet deep with a first production zone at approximately 8750 feet, a second production zone at approximately 8850 feet deep and a third production zone at approximately 9000 feet deep. Casing has been set to approximately 8600 feet in the hole followed by a production casing liner for approximately from 8500 to 10000 feet. Production tubing has been installed to approximately 8700 feet. A hanger liner with packoff **50** has been set between the casing and the production casing liner at approximately 8550 feet. Landing nipples are positioned in the production tubing at approximately 8600 feet. The completion packer **56** is set at about 8450 feet between the casing and the production tubing.

A conventional coiled tubing unit is brought to the well and the well is shut in. The BOP assembly is connected to the wellhead and the injector head assembly is mounted on the BOP assembly. The downhole test/treat assembly **86** is connected to the lower terminus **83** of the conveyance coiled tubing string **82**. When the assembly **86** is being used solely for treatment of a well, as contemplated by this example, the logging tool assembly **93** is an optional component. The downhole test/treat assembly and the conveyance coiled tubing string are deployed into the injector head assembly and the BOP assembly and run into the production tubing **52** to a depth of about 500 feet as shown in FIG. **2**. As shown in FIG. **3**, the injector head assembly **18** is removed, exposing a portion of the conveyance coiled tubing string which is cut off.

As shown in FIG. **4**, the downhole conveyance assembly **72** is connected to the upper terminus **81** of the conveyance coiled tubing string and to the terminus **71** of the coiled tubing string **70**.

As shown in FIG. **5**, the injector head assembly is, reconnected to the BOP stack and the downhole test/treat assembly **86**, the downhole stripper **84** and the downhole conveyance assembly **72** are run into the well to a depth of about 8600 feet. While running into the well, the ACTIV is closed to the annulus **114**. While running in the well the DSRV is closed to reverse flow, up towards the surface. At this depth the downhole stripper **84** is proximate the landing nipples **100**. Sufficient compressive force is then applied to the coiled tubing string **70**, which is transmitted through the conveyance coiled tubing string **82** to the downhole stripper **84** which locks it in place with the landing nipples **100**.

When the downhole stripper is locked in place at about 8600 feet, it also seals the production tubing and isolates it from the rest of the well.

Additional compressive force on the coiled tubing string **70** releases the downhole stripper from the downhole test/treat assembly **86**. This allows the conveyance coiled tubing string **82** to slip through the downhole stripper **84** as more of the coiled tubing string **70** is run in the well as best seen in FIG. **6**.

The packers **94** and **96** are positioned so they straddle the third production zone **62** at about 9,000 feet, as shown in FIG. **7**. Once the straddle packers have reached the desired setting depth, the coiled tubing string **70** will be moved up hole to deactivate the check valves in the DSRV. This will then allow both direct flow down into the well and reverse flow up to the surface. Again, the structure and operation of the DSRV are more fully described in the prior patent application identified above and incorporated herein by reference.

A pump, not shown, pumps fluid down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **86** to inflate the straddle packers **94** and **95** as shown in FIG. **8**. When the packers have been set, the third production zone **62** is isolated from the rest of the well by the packers which seal against the inside circumference of the production casing liner **46**.

Assuming that only the third production zone **62** needs treatment, it is not necessary to reposition the packers from the location shown in FIG. **10**. In order to treat the third production zone **62**, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV to the closed to annulus position and, when weight is set back down, the ACTIV open ports **128** then prevent annular communication. The treatment fluid is pumped down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **86** as shown in FIG. **9** into the third production zone **62**. After a sufficient amount of treatment fluid has been pumped in the well, the pump is stopped.

The coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, and when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**.

The flowpath for the commingled fluid (treatment fluid and formation fluid) is the same as shown in FIG. **10**. The commingled fluid flows from the third production zone, through the downhole test/treat assembly **86**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the open ports **128** of the ACTIV **78** into the annulus **114**. The commingled fluid flows up the annulus **114** to the wellhead and out the wellhead outlet **39**. This flowpath up the annulus instead of the coiled tubing **70** differentiates the present method for the prior art for both testing and treatment of a well. After the formation has cleared itself of the treatment fluid, the production wing valves in the wellhead can be closed to stop the flow.

Once a treatment is completed, the straddle packers can be unset with tension applied and moved uphole to treat another production zone, if necessary. Once all production zones have been treated, the downhole test/treat assembly **86** is retrieved from the well. On the way out of the well, the downhole stripper **84** is disengaged and retrieved with the downhole test/treat assembly.

Operational Example of the Alternative Embodiment of FIG. **11**

The following example is hypothetical example using the alternative embodiment of FIG. **11** to test and treat a well. This example will refer to FIGS. **3**–**10**, however the assembly **86** in these figures should be replaced with the alternative embodiment of the downhole test/treat assembly **122** as shown in FIG. **11**.

A well is approximately 10,000 feet deep with a first production zone at approximately 8750 feet, a second production zone at approximately 8850 feet deep and a third production zone at approximately 9000 feet deep. Casing has been set to approximately 8600 feet in the hole followed by a production casing liner for approximately from 8500 to 10000 feet. Production tubing has been installed to approximately 8700 feet. A hanger liner with packoff **50** has been set between the casing and the production casing liner at approximately 8550 feet. Landing nipples are positioned in the production tubing at approximately 8600 feet. The completion packer **56** is set at about 8450 feet between the casing and the production tubing.

A conventional coiled tubing unit is brought to the well and the well is shut in. The BOP assembly is connected to the wellhead and the injector head assembly is mounted on the BOP assembly. In this hypothetical example the alternative embodiment of the downhole test/treat assembly **122** is substituted for the assembly **86** shown in FIG. **3**. The alternative embodiment of the downhole test/treat assembly **122** with a single packer is connected to the lower terminus **83** of the conveyance coiled tubing string **82**. The alternative embodiment of the downhole test/treat assembly **122** and the conveyance coiled tubing string are deployed into the injector head assembly and the BOP assembly and run into the production tubing **52** to a depth of about 500 feet similar to the apparatus shown in FIG. **2**. The injector head assembly **18** is removed, exposing a portion of the conveyance coiled tubing string which is cut off.

As shown in FIG. **4**, the downhole conveyance assembly **72** is connected to the upper terminus **81** of the conveyance coiled tubing string and to the terminus **71** of the coiled tubing string **70**, except the alternative embodiment of the downhole test/treat assembly **122** is substituted for the assembly **86** shown in FIG. **4**.

As shown in FIG. **5** with the substitution of the assembly **122** for the assembly **86**, the injector head assembly is, reconnected to the BOP stack and the downhole test/treat assembly **122**, the downhole stripper **84** and the downhole conveyance assembly **72** are run into the well to a depth of about 8600 feet. While running into the well, the ACTIV is closed to the annulus **114**. While running in the well the DSRV is closed to reverse flow, up towards the surface. At this depth the downhole stripper **84** is proximate the landing nipples **100**. Sufficient compressive force is then applied to the coiled tubing string **70**, which is transmitted through the conveyance coiled tubing string **82** to the downhole stripper **84** which locks it in place with the landing nipples **100**. When the downhole stripper is locked in place at about 8600 feet, it also seals the production tubing and isolates it from the rest of the well.

Additional compressive force on the coiled tubing string **70** releases the downhole stripper from the downhole test/treat assembly **122**. This allows the conveyance coiled tubing string **82** to slip through the downhole stripper **84** as more of the coiled tubing string **70** is run in the well as best seen in FIG. **6**.

The packer **94** is positioned above the third production zone **62** at about 9,000 feet. As shown in FIG. **11**. Once the packer has reached the desired setting depth, the coiled tubing string **70** will be moved up hole to deactivate the check valves in the DSRV. This will then allow both direct flow down into the well and reverse flow up to the surface. Again, the structure and operation of the DSRV are more fully described in the prior patent application identified above and incorporated herein by reference.

A pump, not shown, pumps fluid down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **122** to inflate the straddle packer **94** as shown in FIG. **11**. When the packer has been set, the third production zone **62** is isolated from the rest of the well by the packers which seal against the inside circumference of the production casing liner **46**.

To test the third production zone, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**. The well is allowed to flow from the third production zone as shown in FIG. **10**, through the downhole test/treat assembly **122**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the ACTIV **78** into the annulus **114**. The formation fluid passes through the wellhead and out the wellhead outlet **39**. The logging tool assembly **93** measures flow, temperature and other variables to test the third production zone **62**. Data from the logging tool **93** can be sent in real time up to the surface by electric wireline logging cable, preinstalled in the coiled tubing. In the alternative, the data can be stored in memory and analyzed after the logging tool is removed from the well. In the preferred embodiment, the data is sent to the surface while the logging tool assembly is still in the well. This alternative embodiment can only be used to test/treat the lowest production zone in a well with multiple completions.

In order to treat the third production zone **62**, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV to the closed to annulus position and, when weight is set back down, the ACTIV open ports **128** then prevent annular communication. The treatment fluid is pumped down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **122** similar to the apparatus as shown in FIG. **9** into the third production zone **62**. After a sufficient amount of treatment fluid has been pumped in the well, the pump is stopped.

The coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, and when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**.

The flowpath for the commingled fluid is similar to the path as shown in FIG. **10**. The commingled fluid flows from the third production zone, through the downhole test/treat assembly **122**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the open ports **128** of the ACTIV **78** into the annulus **114**. The commingled fluid flows up the annulus **114** to the wellhead and out the wellhead outlet **39**. This flowpath up the annulus instead of the coiled tubing **70** differentiates the present method for the prior art for both testing and treatment of a well. After the formation has cleared itself of the treatment fluid, the production wing valves in the wellhead can be closed to stop the flow.

Once a treatment is completed, the packer can be unset with tension applied and retrieved from the well. On the way out of the well, the downhole stripper **84** is disengaged and retrieved with the downhole test/treat assembly **122**.

In some situations, it may only be necessary to treat a well. When the assembly **122** is being used solely for treatment of a well the logging tool assembly **93** is an optional component. Treatment of a well using this alternative embodiment **122** is similar to the prior treatment example, except the assembly **122** is substituted for the assembly **86**.

Operational Example of the Alternative Embodiment as Shown in FIG. 12

The following example is hypothetical example using the alternative embodiment **122** as shown in FIG. **12** to test and treat a well that has a mechanical or inflatable bridge plug **124** that has been previously run and set in the well below the production zone of interest. In this hypothetical example, the bridge plug has been set below the second production zone **60**. This example will refer to FIGS. **3**–**10**, however the assembly **86** in these figures should be replaced with the alternative embodiment of the downhole test/treat assembly **122** as shown in FIG. **12**.

A well is approximately 10,000 feet deep with a first production zone at approximately 8750 feet, a second production zone at approximately 8850 feet deep and a third production zone at approximately 9000 feet deep. Casing has been set to approximately 8600 feet in the hole followed by a production casing liner for approximately from 8500 to 10000 feet. Production tubing has been installed to approximately 8700 feet. A hanger liner with packoff **50** has been set between the casing and the production casing liner at approximately 8550 feet. Landing nipples are positioned in the production tubing at approximately 8600 feet. The completion packer **56** is set at about 8450 feet between the casing and the production tubing. An inflatable bridge plug has been set at about 8875 feet in the well.

A conventional coiled tubing unit is brought to the well and the well is shut in. The BOP assembly is connected to the wellhead and the injector head assembly is mounted on the BOP assembly. In this hypothetical example the alternative embodiment of the downhole test/treat assembly **122** is substituted for the assembly **86** shown in FIG. **3**. The alternative embodiment of the downhole test/treat assembly **122** with a single packer is connected to the lower terminus **83** of the conveyance coiled tubing string **82**. The alternative embodiment of the downhole test/treat assembly **122** and the conveyance coiled tubing string are deployed into the injector head assembly and the BOP assembly and run into the production tubing **52** to a depth of about 500 feet similar to the apparatus shown in FIG. **2**. The injector head assembly **18** is removed, exposing a portion of the conveyance coiled tubing string which is cut off.

As shown in FIG. **4**, the downhole conveyance assembly **72** is connected to the upper terminus **81** of the conveyance coiled tubing string and to the terminus **71** of the coiled tubing string **70**, except the alternative embodiment of the downhole test/treat assembly **122** is substituted for the assembly **86** shown in FIG. **4**.

As shown in FIG. **5** with the substitution of the assembly **122** for the assembly **86**, the injector head assembly is, reconnected to the BOP stack and the downhole test/treat assembly **122**, the downhole stripper **84** and the downhole conveyance assembly **72** are run into the well to a depth of about 8600 feet. While running into the well, the ACTIV is closed to the annulus **114**. While running in the well the DSRV is closed to reverse flow, up towards the surface. At this depth the downhole stripper **84** is proximate the landing nipples **100**. Sufficient compressive force is then applied to the coiled tubing string **70**, which is transmitted through the conveyance coiled tubing string **82** to the downhole stripper **84** which locks it in place with the landing nipples **100**. When the downhole stripper is locked in place at about 8600 feet, it also seals the production tubing and isolates it from the rest of the well.

Additional compressive force on the coiled tubing string **70** releases the downhole stripper from the downhole test/treat assembly **122**. This allows the conveyance coiled tubing string **82** to slip through the downhole stripper **84** as more of the coiled tubing string **70** is run in the well as best seen in FIG. **6**.

The packer **94** is positioned above the second production zone **60**. As shown in FIG. **12**. Once the packer has reached the desired setting depth, the coiled tubing string **70** will be moved up hole to deactivate the check valves in the DSRV. This will then allow both direct flow down into the well and reverse flow up to the surface. Again, the structure and operation of the DSRV are more fully described in the prior patent application identified above and incorporated herein by reference.

A pump, not shown, pumps fluid down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **122** to inflate the packer **94** as shown in FIG. **12**. When the packer has been set, the third production zone **62** is isolated from the rest of the well by the packers which seal against the inside circumference of the production casing liner **46**.

To test the second production zone, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**. The well is allowed to flow from the second production zone through the downhole test/treat assembly **122**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the ACTIV **78** into the annulus **114**. The formation fluid passes through the wellhead and out the wellhead outlet **39**. The logging tool assembly **93** measures flow, temperature and other variables to test the third production zone **62**. Data from the logging tool **93** can be sent in real time up to the surface by electric wireline logging cable, preinstalled in the coiled tubing. In the alternative, the data can be stored in memory and analyzed after the logging tool is removed from the well. In the preferred embodiment, the data is sent to the surface while the logging tool assembly is still in the well.

In order to treat the second production zone **62**, the coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV to the closed to annulus position and, when weight is set back down, the ACTIV open ports **128** then prevent annular communication. The treatment fluid is pumped down the coiled tubing string **70**, through the downhole conveyance assembly **72**, through the conveyance coiled tubing string **82**, and through the downhole test/treat assembly **122** similar to the apparatus as shown in FIG. **9** into the third production zone **62**. After a sufficient amount of treatment fluid has been pumped in the well, the pump is stopped.

The coiled tubing string is then put into tension sufficiently to cycle the mechanism in the ACTIV **78** to the open to annulus position and, and when weight is set back down, the ACTIV open ports **128** then allow annular communication. In other words, fluid flows towards the surface through the conveyance coiled tubing string **82** through the connector **80**, and through the open ports to the annulus **114**.

The flowpath for the commingled fluid is similar to the path as shown in FIG. **10**, except he second production zone is being treated and not the third zone. The commingled fluid flows from the second production zone, through the downhole test/treat assembly **122**, through the conveyance coiled tubing string **82**, through the downhole conveyance assembly **72** and out the open ports **128** of the ACTIV **78** into the annulus **114**. The commingled fluid flows up the annulus **114** to the wellhead and out the wellhead outlet **39**. This flowpath up the annulus instead of the coiled tubing **70** differentiates the present method for the prior art for both testing and treatment of a well. After the formation has cleared itself of the treatment fluid, the production wing valves in the wellhead can be closed to stop the flow.

Once a treatment is completed, the packer can be unset with tension applied and retrieved from the well. On the way out of the well, the downhole stripper **84** is disengaged and retrieved with the downhole test/treat assembly **122**.

In some situations, it may only be necessary to treat a well. When the assembly **122** is being used solely for treatment of a well the logging tool assembly **93** is an optional component. Treatment of a well using this alternative embodiment **122** is similar to the prior treatment example, except the assembly **122** is substituted for the assembly **86**.

What is claimed is:

1. A method for testing a well with production tubing in place and multiple production zones comprising:

connecting a downhole test assembly and downhole stripper to a conveyance coiled tubing string;

deploying the downhole test assembly, downhole stripper and the conveyance coiled tubing string in the well;

running a sufficient length of the conveyance coiled tubing string into the well;

hanging the conveyance coiled tubing string, the downhole test assembly and the downhole stripper off of a BOP and removing the injector head assembly to expose a portion of the conveyance coiled tubing string;

cutting the conveyance coiled tubing string and connecting a downhole conveyance assembly and coiled tubing string;

running the coiled tubing string, the downhole conveyance assembly, the coiled tubing string, the downhole stripper and the test assembly into the production tubing;

engaging the downhole stripper with the production tubing;

running the coiled tubing string and the downhole conveyance assembly into the well and the conveyance coiled tubing string through the downhole stripper to a depth where the test assembly is adjacent a production zone;

setting at least one packer;

flowing formation fluid from the production zone up to and out the wellhead, through the test assembly, through the conveyance coiled tubing string, through a portion of the downhole conveyance assembly and through the annulus between the coiled tubing string and the production tubing; and

testing the production zone.

2. A method for fluid treatment of a well with production tubing in place and multiple production zones comprising:

connecting a downhole treat assembly and downhole stripper to a conveyance coiled tubing string;

deploying the downhole treat assembly, downhole stripper and the conveyance coiled tubing string in the well;

running a sufficient length of the conveyance coiled tubing string into the well;

hanging the conveyance coiled tubing string, the downhole treat assembly and the downhole stripper off of a BOP and removing the injector head assembly to expose a portion of the conveyance coiled tubing string;

cutting the conveyance coiled tubing string and connecting a downhole conveyance assembly and coiled tubing string;

running the coiled tubing string, the downhole conveyance assembly, the conveyance coiled tubing string, the downhole stripper and the downhole treat assembly into the production tubing;

engaging the downhole stripper with the production tubing;

running the coiled tubing string and the downhole conveyance assembly into the well and the conveyance coiled tubing string through the downhole stripper to a depth where the downhole treat assembly is adjacent a production zone;

setting at least one packer;

pumping a treatment fluid down through the coiled tubing string, through the downhole conveyance assembly, through the conveyance coiled tubing string and through the treat assembly into a single production zone;

flowing treatment fluid and formation fluid from the production zone up to and out the wellhead through the downhole treat assembly, through the conveyance coiled tubing string, through a portion of the downhole conveyance assembly and through the annulus between the coiled tubing string and the production tubing;

unsetting all packers;

retrieving the downhole treat assembly, the conveyance coiled tubing string, the downhole stripper, the downhole conveyance assembly and the coiled tubing string from the well and disengaging the downhole stripper on the way out.

3. A method for improving production of a well with production tubing in place and multiple production zones comprising:

a) testing each production zone by:

connecting an downhole test/treat assembly and downhole stripper to a conveyance coiled tubing string;

deploying the downhole test/treat assembly, downhole stripper and the conveyance coiled tubing string in the well;

running a sufficient length of the conveyance coiled tubing string into the well;

hanging the conveyance coiled tubing string, the downhole test/treat assembly and the downhole stripper off of a BOP and removing the injector head assembly to expose a portion of the conveyance coiled tubing string;

cutting the conveyance coiled tubing string and connecting a downhole conveyance assembly and coiled tubing string;

running the coiled tubing string, the downhole conveyance assembly, the conveyance coiled tubing string, the downhole stripper and the downhole test/treat assembly into the production tubing;

engaging the downhole stripper with the production tubing;

running the coiled tubing string and the downhole conveyance assembly into the well and the conveyance coiled tubing string through the downhole stripper to a depth where the downhole test/treat assembly is adjacent a production zone;

setting at least one packer;

flowing formation fluid from the production zone up to and out the wellhead through the downhole test/treat assembly, through the conveyance coiled tubing string, through a portion of the downhole conveyance assembly and through the annulus between the coiled tubing string and the production tubing; and

testing the production zone;

b) treating at least one production zone by:

pumping a treatment fluid down through the coiled tubing string, through the downhole conveyance assembly, through the conveyance coiled tubing string and through the downhole test/treat assembly into at least one production zone; and

flowing treatment fluid and formation fluid from the at least one production zone up to and out the wellhead through the downhole test/treat assembly, through the conveyance coiled tubing string, through a portion of the downhole conveyance assembly and through the annulus between the coiled tubing string and the production tubing, the annulus being located above the downhole stripper.

4. The method of claim **3** further including:

testing each production zone by;

flowing formation fluid from the production zone up to and out the wellhead through the downhole test/treat assembly, through the conveyance coiled tubing string, through a portion of the downhole conveyance assembly and through the annulus between the coiled tubing string and the production tubing, the annulus being above the downhole stripper; and

testing the production zone.

5. The method of claim **4** further including:

pumping a treatment fluid down through the coiled tubing string, through the downhole conveyance assembly, through the conveyance coiled tubing string and through the downhole test/treat assembly into at least one production zone; and

flowing treatment fluid and formation fluid from the at least one production zone up to and out the wellhead, through the downhole test/treat assembly, through the conveyance coiled tubing string, through a portion of the downhole conveyance assembly and through the annulus between the coiled tubing string and the production tubing, the annulus being located above the downhole stripper.

6. The method of claim **4** further including:

after positive test results;

unsetting all packers; and

retrieving the downhole test/treat assembly, the conveyance coiled tubing string, the downhole stripper, the downhole conveyance assembly and the coiled tubing string from the well and disengaging the downhole stripper on the way out.

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